Journal of Cleaner Production 335 (2022) 130045

Contents lists available at ScienceDirect

Journal of Cleaner Production

journal homepage: www.elsevier.com/locate/jclepro

# The techno-economics potential of hydrogen interconnectors for electrical energy transmission and storage

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ARTICLE INFO

Handling Editor: Jiri Jaromir Klemeš

*Keywords:*
Hydrogen Interconnector System
Hydrogen economy
High Voltage Direct Current Systems
Techno-economic analysis
Levelised Cost of Electricity
Levelised Cost of Storage

ABSTRACT

This research introduces a 'Hydrogen Interconnector System' (HIS) as a novel method for transporting electrical energy over long distances. The system takes electricity from stranded renewable energy assets, converts it to hydrogen in an electrolyser plant, transports hydrogen to the demand centre via pipeline, where it is reconverted to electricity in either a gas turbine or fuel cell plant. This paper evaluates the competitiveness of the technology with High Voltage Direct Current (HVDC) systems, calculating the following techno-economic indicators; Levelised Cost Of Electricity (LCOE) and Levelised Cost Of Storage (LCOS). The results suggest that the LCOE of the HIS is competitive with HVDC for construction in 2050 with distance beyond 350 km in case of all scenarios for a 1 GW system. The LCOS is lower than an HVDC system using large scale hydrogen storage in 6 out of 12 scenarios analysed, including for construction from 2025. The HIS was also applied to three case studies, with the results showing that the system outperforms HVDC from LCOS perspectives in all cases, and has 15%–20% lower investment costs in 2 studies analysed.

## 1. Introduction

With an increasing recognition of the effects of climate change, countries have begun implementing roadmaps outlining their approach to achieve net-zero targets. Increasing the amount of renewable energy resources to replace fossil fuels is a key element of these policies, with the United Kingdom (UK) targeting 40 GW of offshore wind by 2030 (Department for Business, Energy and Industrial Strategy, 2020), and an additional capacity of 35 GW needed to achieve a zero carbon economy by 2050 (Offshore Renewable Energy Catapult, 2020). In addition to more developed renewable technologies such as wind and solar, policy makers have identified hydrogen as a key solution to decarbonise multiple sectors over time—the EU aims to meet 8%–24% of total energy demand with hydrogen by 2050, equal to up to 2250 TWh (Fuel Cells and Hydrogen Joint Undertaking, 2019). To produce 'green' hydrogen (hydrogen produced by renewable resources), the European Union (EU) aims to deploy at least 45 GW of electrolysers powered by renewable electricity in the next 30 years, producing up to 10 million tonnes of hydrogen.

To enable the widespread use of renewable hydrogen, it is essential that a hydrogen transportation infrastructure is developed. In the EU, 11 gas infrastructure companies have expressed their vision for a 'European Hydrogen Backbone', proposing the creation of a 23,000 km dedicated pipeline network by 2040 (Gas for Climate, 2020). Similarly, the UK National Grid is exploring linking industrial clusters with a 2000 km pipeline network built as early as 2030 (National Grid Group, 2021). These proposals are heavily influenced by the need to increase security of supply; with renewable resources rarely co-located with demand, a hydrogen network would allow the supply of green hydrogen to reach end users.

One option that could benefit from the deployment of a hydrogen network is the utilisation of hydrogen interconnectors to transport electrical energy over great distances. This has the potential not only to meet increased electricity demand, but also to further improve security of supply through the leveraging of hydrogen storage to compensate for the intermittent nature of renewable energy technologies, reducing the cost of renewable electricity to consumers.

This paper presents a model for a novel 'Hydrogen Interconnector System' (HIS), analysing the techno-economics of the system from LCOE and LCOS perspectives. The lowest cost HIS is first identified, and then compared to an equivalent HVDC system under different scenarios and sensitivities, and the model applied to three case studies to evaluate the system when used as an interconnector.

Existing research in the field of hydrogen involves studies in production—including techno-economic assessments (Yukesh Kannah

*Abbreviations:* HIS, Hydrogen Interconnector System; HVAC, High Voltage Alternating Current; HVDC, High Voltage Direct Current; LCOE, Levelised Cost of Electricity; LCOS, Levelised Cost of Storage; PEM, Proton Exchange Membrane; FC, Fuel Cell

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https://doi.org/10.1016/j.jclepro.2021.130045
Received 2 May 2021; Received in revised form 8 December 2021; Accepted 8 December 2021
Available online 1 January 2022

et al., 2021), technical reviews (Shiva Kumar and Himabindu, 2019) and experimental investigation into novel production methods (Sangeetha et al., 2021). In addition, there is significant research into transmission network optimisation—some investigating specific locations (Keith and Leighty, 2002), with others focusing on end-use (Baufumé et al., 2013). While studies in the techno-economics of hydrogen transport do exist, there is general disagreement on how economical hydrogen pipelines are when compared to HVDC transmission, with some conclusions made in favour of hydrogen pipelines (Taieb and Shaaban, 2019) and others suggesting hydrogen pipelines are not economical (Keith and Leighty, 2002). In addition, more accurate cost data has become available since their publication. This model aims to contribute to the research field by leveraging this data to analyse the costs of hydrogen transmission under different scenarios, enabling a comprehensive techno-economic comparison with HVDC, providing more insight into the feasibility of hydrogen interconnectors between 2020 and 2050.

It is to be noted that model for the HIS specifically generated techno-economic indicators as outputs to be analysed and compared to HVDC. The calculations mentioned in Section 4 do not capture the system dynamics and its precise operation, as well as the interactions that the HIS could have with surrounding energy systems.

## 2. Literature review and state-of-the-art of hydrogen pipelines

### 2.1. An overview of hydrogen pipelines

Despite hydrogen pipelines being in use for almost a century, there are currently only 4500 km of hydrogen pipelines globally (Scottish Government, 2020), compared to over 160,000 km of oil and gas pipelines (GlobalData, 2018). As such, research into hydrogen pipeline technology is relatively scarce compared with other pipeline transportation methods. Transmission of gaseous hydrogen via pipeline has many similarities with that of natural gas: following this, most literature investigates how the differences between hydrogen and methane translate to pipeline design and cost.

From a technical perspective, four main differences exist between hydrogen and natural gas pipelines (Ball and Wietschel, 2009):

- The volumetric energy density of hydrogen is 1/3 that of methane
- Hydrogen embrittlement of steel must be accounted for in pipeline design
- Compression has higher capital and operational costs for hydrogen systems
- High pipeline utilisation is required for economic feasibility

Each of these factors require adjustments to be made to traditional natural gas pipeline designs, which commonly result in higher construction costs (Parker, 2004).

Due to the lower energy density of hydrogen compared to methane, hydrogen pipelines require larger capacities than natural gas pipelines to transport the same amount of energy (Witkowski et al., 2017). This would be achieved either through compressing the hydrogen to higher inlet pressures or designing pipelines with larger internal diameters. Most hydrogen transmission pipeline designs have typical operating pressures of up to 10 MPa and internal diameters of 50–120 cm, with some concepts having pressures of up to 100 MPa (Fekete et al., 2015).

Hydrogen embrittlement is a key constraint in hydrogen pipeline design, particularly in the choice of materials and pipe wall thickness (Rui et al., 2011). Higher strength steels are desirable when considering pipeline economics—with materials comprising 26% of natural gas pipeline costs, lower wall thicknesses have the potential to drastically reduce total costs while maintaining safety standards. However, higher strength steel is more susceptible to hydrogen embrittlement, a process where metals become brittle due to the diffusion of hydrogen into the material (Dear and Skinner, 2017). As such, the majority of current hydrogen pipeline projects use of low strength steels with large thicknesses, following ASME B31.12 codes (Hayden and Stalheim, 2009), resulting in a material cost several times that of natural gas (Briottet et al., 2012).

In terms of storage of gaseous hydrogen, the main forms currently discussed in literature are salt cavern storage and compressed storage in pressurised tanks. Both methods are proposed for utilisation alongside long distance hydrogen transmission pipelines, enabling storage in the region of PWh (Andersson and Grönkvist, 2019). However, for the purposes of providing smaller scale storage capacity, 'linepacking' can be used within pipelines. This has the potential to enable firming of renewable supply, potentially reducing prices within the wholesale electricity market (Panfilov, 2016). While the benefits of such a storage medium have been discussed in existing literature, no existing research investigates the quantitative benefits from a LCOS perspective.

### 2.2. Hydrogen transmission networks

The majority of current literature relating to the development and construction of a hydrogen pipeline infrastructure focuses on the design and optimisation of hydrogen transmission networks, focusing on applying optimisation methods to specific regions, including Germany (Baufumé et al., 2013) and France (André et al., 2014). They rely on pipeline cost equations generated by Parker (2004) and Yang and Ogden (2007) to optimise the cost and capacity of a network, calculating the optimal pipeline diameter, length and location to achieve a given demand while minimising cost.

While these studies provide useful insight into the ideal location of hydrogen transmission infrastructure, they have some key shortcomings. Firstly, the total cost of the designed systems are not investigated in great detail, providing scope to further investigate the techno-economics of hydrogen pipeline transmission. Secondly, the majority of these models do not consider the production method of hydrogen. Despite 95% of hydrogen currently being produced from fossil fuels, key hydrogen roadmaps cite electrolysis as the main technology to be used to scale production, both globally (International Energy Agency, 2019) and within Europe (Fuel Cells and Hydrogen Joint Undertaking, 2019). Following this, there is significant scope to incorporate hydrogen production into the techno-economics of a 'green' hydrogen transmission system, to provide a clearer picture of the levelised costs of future projects. Of existing literature covering the optimisation of hydrogen transmission networks, one piece of research considers whether to transport energy as hydrogen or as electricity, with the aim being to minimise the total cost of network while meeting transport demand in the UK (Samsatli et al., 2016). The research indicates that all of the UK's transport demand can be met with onshore wind through deployment of a hydrogen + electricity network. Due to the uncertainty of input data regarding electrolyser/fuel cell costs, sensitivity analyses are recommended as a future step to improve upon the research. In addition, the research only considers compressed and underground hydrogen storage, and recommends investigation into pipeline storage as a means to further develop a hydrogen transmission model.

### 2.3. Techno-economic analysis of electrical energy transmission

Methods for analysis and optimisation of energy infrastructure are techno-economic indicators, namely LCOE and LCOS (Raikar and Adamson, 2020). These indicators enable an economic comparison to be made between different technologies for the purpose of electrical energy transport and storage respectively.

Some literature does exist which compares the techno-economics of hydrogen pipelines and HVAC/HVDC transmission. These compare the LCOE of each technology, based on the costs of construction, operation and maintenance, and additional factors. There is some disagreement on which system is the most economical for electricity

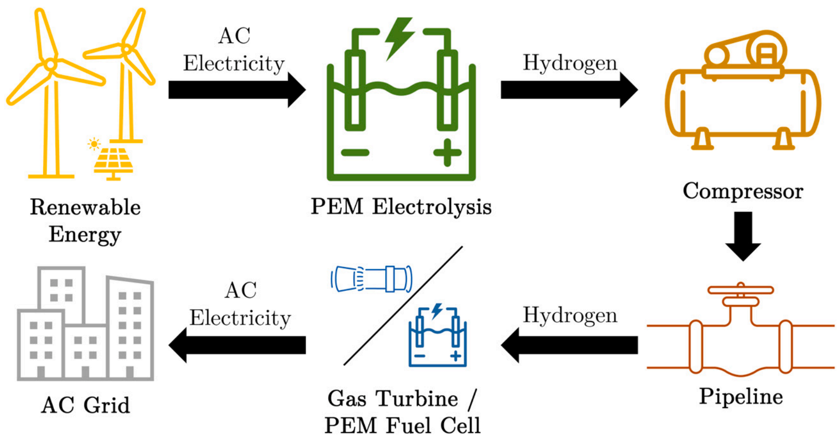


**Fig. 1.** Schematic of HIS, including connections to energy source and grid.

transport, with (Taieb and Shaaban, 2019) suggesting a pipeline system is less expensive then HVDC at distances larger than 740 km, while (Keith and Leighty, 2002) finds that HVDC transmission delivers a LCOE 0.08–0.12 $/kWh less than hydrogen pipelines, for the case of transmission from North Dakota to Chicago (1600 km). Further research into the cost of a hydrogen pipeline system would be beneficial to provide more insight into the economic benefits relative to HVDC. In addition, there are various considerations which these existing studies do not include. Incorporation of learning curves of electrolysers, onshore/offshore configurations and more accurate cost data could significantly improve upon these models, providing a more accurate picture of the cost of a hydrogen pipeline interconnector. Furthermore, as mentioned in Samsatli et al. (2016), sensitivity analysis and research into the storage benefits of hydrogen pipelines would be useful when comparing the effectiveness of such a system with HVDC counterparts.

## 3. Hydrogen interconnector model

This section presents the technical model of the HIS, describing the main components of the system and its operation.

### 3.1. System overview

The HIS enables electrical energy to be transported from stranded renewable resources to areas of large demand, while providing embedded storage to account for intra-day and seasonal imbalances between supply and demand. The system operates by converting electricity to gaseous hydrogen at the source, pressurising the hydrogen and transmitting it along long distances via a pipeline, where it is reconverted back to electricity at the centre of demand. Storage is provided as linepack within the pipeline. This system is intended to be used to transport electricity in the region of MWs to GWs, similar to that of current high voltage transmission lines.

Fig. 1 provides a high level schematic of the system, and Table 1 highlights the main technical elements of the system.

### 3.2. Hydrogen generation from electricity

To convert energy generated from wind or solar sources to hydrogen, the electricity is used to split water into hydrogen and oxygen. This occurs at an electrolyser plant, which is assumed to be able to convert up to 2 GW of input electricity into hydrogen. However, the largest electrolyser plants that currently exist have capacities of up to 20 MW (International Energy Agency, 2019). As such, this model considers a PEM electrolyser plant — despite currently having low capacities, PEM systems can be modularly 'stacked' to achieve the desired scale, without impacting efficiency or output pressure (International Energy Agency, 2019). In addition, the technology is less mature than conventionally used alkaline electrolysis; as such production is expected to increase to GW scale in the future. PEM electrolysers are also highly flexible systems, enabling operation ranges from zero load to 160% capacity, making it suitable for an intermittent input.

The electrolyser plant takes DC electricity at input provided by an AC/DC converter at the energy source, and requires 9L of feedstock water to produce 1 kg hydrogen gas (International Energy Agency, 2019). PEM systems output high purity hydrogen at pressures of between 3 and 6 MPa, so a compressor is required to increase the pressure to 10–20 MPa at pipeline inlet, depending on the required flow rate in the pipeline. Centrifugal compressors are commonly used in natural gas pipelines, and so are considered in this model (Witkowski et al., 2017). Following Nexant Inc. (2008), an allowable pressure ratio per compressor stage of 2:1 is assumed, resulting in 2–4 stages required in the system.

### 3.3. Hydrogen transmission and storage

Flow of hydrogen is enabled through the pressure loss between inlet and outlet of the hydrogen pipeline, which is intended to be broadly similar to that of a natural gas pipeline, with slight adjustments made to account for leakage and embrittlement. The pipeline is constructed of API 5L Grade X52 carbon steel, and internal diameter of 50–120 cm. The pipeline delivers hydrogen at an outlet pressure of 3.55 MPa, and the inlet pressure is varied to achieve the desired flow rate of the system.

To enable storage within the pipeline, it is assumed that the operating pressure of the pipeline can be reduced by as much as 25% up to 2 times a day, enabling energy to be stored and released on a daily or seasonal timescale.

### 3.4. Conversion of hydrogen to electricity

Two technologies are considered in the interconnector model for the purpose of reconverting hydrogen to electricity: hydrogen-fired gas turbines (H2GT) and PEM fuel cells (PEMFC).

In the H2GT, the hydrogen is ignited and expanded to drive a generator, outputting AC electricity. It is assumed that multiple turbines operate in parallel—a base size of 50–100 MW is assumed, with the total number of turbines depending on the size of the system. There are few H2GTs in operation today, however the same technology as natural gas-fired combined cycle gas turbines can be used with hydrogen, giving confidence that such a system could be achieved (Element Energy, 2019).

As with the electrolysis plant, the fuel cell system will consist of multiple H2GTs, assuming they can be modularly 'stacked' to produce a large scale plant. The system outputs DC electricity, and as such will require a DC–AC converter to provide AC electricity to end users.

**Table 1**
Technical overview of hydrogen interconnector model.

| | |
|---|---|
| Delivered Power | 50–4,000 MW |
| Length | 50–2,500 km |
| System Lifetime | 40 years |
| Efficiency | 24.1–48.6% |
| $H_2$ to $e^-$ Conversion | H2GT/Fuel Cell |
| Pipeline Diameter | 50–120 cm |
| Pipeline Configuration | Onshore/Offshore |

## 4. Methodology

LCOE method was used to evaluate costs of the HIS, and compare it with the equivalent HVDC system in the context of transporting electricity. The simplified LCOE equation is shown in Eq. (1). This equation was broken down into lifetime Capital Expenditure ($CAPEX$) and Operating Expenditure ($OPEX$), which was annualised to each year $t$. A discount rate, $i$ is applied to both the $OPEX$ and electricity output $Q_{el}$ to account for the investment cost over the lifetime $n$. The full equation is given in Eq. (2). This equation was used to calculate LCOS by taking $Q_{el}$ as the annual electricity discharged by the system following (Jülch, 2016). In all calculations, a value of $i$ of 3% was used, corresponding to a 'stable market environment with high investment security' as specified by the International Energy Agency (International Energy Agency, 2020).

$$\mathrm{LCOE} = \frac{\text{Sum of Costs Over Lifetime}}{\text{Sum of Electrical Energy Produced Over Lifetime}} \tag{1}$$

$$LCOE = \frac{CAPEX + \sum_{t=1}^{n} \frac{OPEX_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{Q_{el}}{(1+i)^t}} \tag{2}$$

The breakdown of $CAPEX$ and $OPEX$ is shown in Eqs. (3) and (4). The $CAPEX$ takes into account the total initial investment for the system $C_{inv}$ and the total replacement costs over the system lifetime $C_{repl,t}$. The total $OPEX$ is comprised of the total Operating and Maintenance ($O\&M$) costs for all system components, and the cost of electricity at the electrolyser and compressor $E_c$.

$$CAPEX = C_{inv} + C_{repl,t} \tag{3}$$

$$OPEX = O\&M + E_c \tag{4}$$

All of the components considered in the model besides the compressor are considered to be in early market stages, meaning that technical and cost advancements are expected in the future. In particular, the technical capabilities, costs and scalability of PEM electrolysers and PEMFCs are expected to drastically improve over time (Offshore Renewable Energy Catapult, 2020). Furthermore, few hydrogen pipelines are in operation today, with up to 20,000 km of additional capacity expected to be built in mainland Europe (Gas for Climate, 2020). This may result in decreasing pipeline costs as production increases. In addition, renewable energy technologies are still decreasing in price: in the case of onshore wind, agreed strike prices of as low as 2¢ per kWh are predicted for 2050 (International Renewable Energy Agency: IRENA, 2019).

Following the importance of these changes and uncertainty about future costs, data from various roadmaps and research was gathered and incorporated into the model to produce levelised costs for three scenarios: 'high' (most optimistic), 'medium' (base level), and 'low' (least optimistic), with each scenario applied to a construction year in 2020, 2025, 2030 and 2050, generating a total of 3 input data sets.

The data set for the 'medium' scenario is shown in Table 2, with all financial data adjusted to $\$_{2020}$. All 3 scenario data sets are given in the Appendix. Sections 4.1 to 4.4 detail the key financial and technical considerations for each element of the system that contribute to the levelised cost calculations and scenarios.

**Table 2**
Medium scenario data set.

| | 2020 | 2025 | 2030 | 2050 |
|---|---|---|---|---|
| **Electrolyser** (Schmidt et al., 2017) | | | | |
| Efficiency (%,LHV) | 58% | 64% | 65% | 70.5% |
| Operating Lifetime (h) | 60,000 | 67,500 | 75,000 | 125,000 |
| CAPEX ($/kW) | 1,350 | 1,025 | 700 | 450 |
| O&M (%CAPEX) | 1.5% | 1.5% | 1.5% | 1.5% |
| Replacement Cost (%CAPEX) | 15% | 14% | 12% | 12% |
| Max. Output Pressure (MPa) | 5.5 | 6.3 | 7.0 | 10.0 |
| **Compressor** (Penev et al., 2019) | | | | |
| O&M (%CAPEX) | 3% | 3% | 3% | 3% |
| Operating Lifetime (y) | 10 | 10 | 10 | 10 |
| Replacement Cost (%CAPEX) | 100% | 100% | 100% | 100% |
| **Pipeline** (Rui et al., 2011) | | | | |
| O&M (%CAPEX) | 5% | 5% | 5% | 5% |
| EU Backbone Length (km) | 1,598 | 1,649 | 1,700 | 5,725 |
| Material Cost, 8% L.R. (%) | 100% | 100% | 99% | 85% |
| Labour Cost, 14.2% L.R.(%) | 100% | 99% | 99% | 74% |
| **Gas Turbine** (Jülch, 2016) | | | | |
| Efficiency (%, LHV) | 57.8% | 58.3% | 58.8% | 60% |
| CAPEX ($/kW) | 794 | 786 | 779 | 767 |
| Fixed O&M ($/MW/y) | 25,664 | 25,488 | 25,312 | 24,961 |
| Variable O&M ($/MWh) | 4.90 | 4.85 | 4.81 | 4.73 |
| Replacement Cost (%CAPEX) | 100% | 100% | 100% | 100% |
| **Fuel Cell** (International Energy Agency, 2019) | | | | |
| Efficiency (%,LHV) | 44% | 47% | 52% | 60% |
| Operating Lifetime (h) | 60,000 | 67,500 | 75,000 | 125,000 |
| CAPEX ($/kW) | 2,960 | 2,370 | 1,750 | 610 |
| O&M (%CAPEX) | 1.5% | 1.5% | 1.5% | 1.5% |
| Replacement Cost (%CAPEX) | 15% | 14% | 12% | 12% |
| **Feedstock/Input Electricity** (International Renewable Energy Agency: IRENA, 2019) | | | | |
| Onshore Electricity Cost ($/MWh) | 50 | 45 | 40 | 25 |
| Offshore Electricity Cost ($/MWh) | 150 | 110 | 70 | 50 |
| Water ($/m$^3$) | 1.60 | 1.60 | 1.60 | 1.60 |
| **HVDC System** (RealiseGrid, 2008) | | | | |
| Total Efficiency (%) | 98.2% | 98.2% | 98.2% | 98.2% |
| Overhead Line Cost (M$/km) | 0.3 | 0.3 | 0.3 | 0.3 |
| Underground Line Cost (M$/km) | 1.5 | 1.5 | 1.5 | 1.5 |
| Sub-sea Line Cost (M$/km) | 2.6 | 2.6 | 2.6 | 2.6 |
| **Electricity Conversion** (RealiseGrid, 2008) | | | | |
| DC–AC Converter (M$) | 151 | 151 | 151 | 151 |
| AC–DC Converter (M$) | 151 | 151 | 151 | 151 |

### 4.1. Electrolyser

The initial capital cost of the PEM electrolysis plant was considered based on the cost per kW of input electricity, with data sourced from the International Energy Agency 'Future of Hydrogen' report (International Energy Agency, 2019). The decrease in CAPEX of the electrolyser is expected to be driven primarily by the scaling up of production over time, resulting in learning rate effects. The operating lifetime of the system was taken as the lifetime of the electrolyser stack, with technological improvements in the stack increasing the durability of the electrolyser over time. Following this, it was assumed that at end of life, a complete replacement was not necessary. Instead, the replacement cost was taken as the % of CAPEX required to replace and/or repair the electrolyser stack, with this value decreasing over time in line with improvements in resiliency. The total replacement cost was calculated based on the CAPEX/kW for each replacement year, interpolating between data provided for 2020–2050.

The OPEX of the electrolyser was comprised of the cost of input electricity, feedstock water and O&M costs. The cost of water was taken as a fixed \$1.60 per m$^3$ in all scenarios (International Energy Agency, 2019). The electricity cost was taken from data provided by the IRENA 'Future of Wind' report (International Renewable Energy Agency: IRENA, 2019) for onshore and offshore wind energy prices. Changes in the LCOE of wind were taken into account across the lifetime of the system, assuming that the costs do not decrease beyond 2050.

Technological improvements were expected to result in increasing the maximum output pressure of the electrolyser. This value was taken into account to create 'compressorless' scenarios, where the electrolyser can achieve the desired pressure at inlet to the pipeline without the need for additional compression.

### 4.2. Compressor

In cases where pressurisation was required at the pipeline inlet, the CAPEX and OPEX of the compressor were added to the LCOE calculation.

Compressor CAPEX is directly related to the power required at the shaft to pressurise incoming hydrogen, as shown in Eq. (5) (Christensen, 2020).

$$P = Q * \frac{ZTR}{M\eta} * \frac{N\gamma}{\gamma - 1} * \left( \frac{P_{out}}{P_{in}}^{\frac{\gamma-1}{N\gamma}} - 1 \right) \tag{5}$$

The equation calculates the required shaft power $P$ for a compressor with $N$ stages, to achieve an increase between the pressure at inlet $P_{in}$ and outlet $P_{out}$, considering the incoming flow rate $Q$, compressibility $Z$, and molecular mass $M$ of hydrogen. Constants $\gamma$ and $R$ are the ratio of specific heat (1.4) and the universal ideal gas constant (8.314 $\frac{J}{mol\,K}$) respectively. The inlet temperature $T$ was taken as 298.15 K, corresponding to the outlet pressure of the electrolysis plant. The power required is scaled by the efficiency of the compressor $\eta$, taken to be 88% (Nexant Inc., 2008). To calculate the final CAPEX value, the value of $P$ was used as an input to a set of equations computing compressor CAPEX, which were averaged following the method used in Christensen (2020).

### 4.3. Pipeline

The construction cost of a natural gas pipeline can be separated into the following factors:

- Materials
- Labour
- Miscellaneous
- Right of Way

Miscellaneous costs refer to regulatory filing fees, administration and overhead, surveying, supervision, contingencies and allowances for construction funds (Parker, 2004). Parker (Parker, 2004) has created component-wise cost equations by plotting the costs of existing natural gas pipeline projects in the United States against a construction factor, and fitting a line of best fit to the data. This produces a set of cost equations as a function of diameter and length. These equations have been used to calculate the total CAPEX of the hydrogen gas pipeline, increasing the cost of materials by 50% to account for greater wall thicknesses to reduce embrittlement, and increasing labour costs by 25% due to the assumed higher weld costs to reduce leakage. The O&M cost is expected to comprise predominantly of the cost of 'pigging' the pipeline to identify leaks and defects.

Learning rates have also been applied to the material and labour costs at a decrease 8 and 14.2% respectively per doubling of pipeline production (Rui et al., 2011). The increase in pipeline production was calculated assuming the growth of the EU Hydrogen Backbone reflects the increase in global capacity of hydrogen pipelines. Data on the total length of the network is available up to 2040—it has been assumed that 50% of the network will consists of novel hydrogen pipelines. The 'medium' scenario assumes network construction ceases at 2040, and the 'high' scenario assumes continued growth in the network until 2050. The 'low' scenario assumes that no such network will be built, with no learning rate applied to the pipeline costs.

### 4.4. $H_2$ to electricity conversion

The costs of a H2GT are sourced from Element Energy (2019), with a CAPEX/kW of output electricity considered, and the OPEX consisting of fixed and variable O&M costs. The data is provided under First, Second and Nth Of A Kind scenarios (FOAK, SOAK, NOAK) which are translated directly into the costs for 2020, 2030 and 2050. These are small cost improvements relative to other components in the model, as the technology broadly follows that of conventional gas turbines, which are a mature technology.

Economic and technical inputs for the PEMFC broadly share the same approach with the PEM electrolyser plant. Costs are taken from the Fuel Cells and Hydrogen Joint Undertaking report, which provides estimations for capital costs of PEMFCs for 2020 through to 2030 (Fuel Cells and Hydrogen Joint Undertaking, 2014). The CAPEX/kW of output electricity is higher than that of the electrolyser in all scenarios due to the relative infancy of large scale stationary PEMFC technology. To fit the data to 2050, it was assumed that the costs continue to decrease at the same rate between 2030 and 2050 for all scenarios, resulting in costs which are nearly identical with the electrolyser. Given the similarity in technology, the stack lifetime, OPEX and replacement costs (as a % of CAPEX) are taken to be identical to that of the electrolyser.

### 4.5. HVDC system

To compare the levelised costs of the HIS with HVDC, a model was created which achieves the same electricity output over an equivalent distance, excluding the additional storage capability of the pipeline. The model consists of two ±300 kV cables connecting the output of the renewable energy source to the demand centre, reconverting the DC electricity to AC via a grid scale converter. Costs for the cable and converter have been sourced from the RealiseGrid review of costs of transmission infrastructures, with data sourced for overhead, underground and sub-sea configurations (RealiseGrid, 2008). Given the maturity of the technology, no cost or technology improvements with time have been considered.

To enable the HIS and HVDC systems to be compared from a LCOS perspective, it was necessary to include the costs of an additional storage system within the HVDC system, as an HVDC line lacks any form of embedded storage. As such, the costs of storing energy in the form of hydrogen were added to the costs of the HVDC system. The storage system considered consists of an electrolyser plant, compressor and salt cavern storage, with a gas turbine used at the outlet of the salt cavern to release the stored energy as electricity. Therefore, all costs and technical data used in the LCOS calculation are identical to that of Table 2, except for the cost of salt cavern storage, which was assumed to be 0.3 \$/kWh of stored energy, following Jülch (2016).

## 5. Results and discussion

### 5.1. LCOE analysis

Fig. 2 shows the LCOE for each scenario, based on construction years in 2020, 2025, 2030 and 2050. The LCOE has been calculated for the base case of an onshore HIS delivering 1 GW of electricity to the grid, at a distance of 100 km between an onshore wind energy source

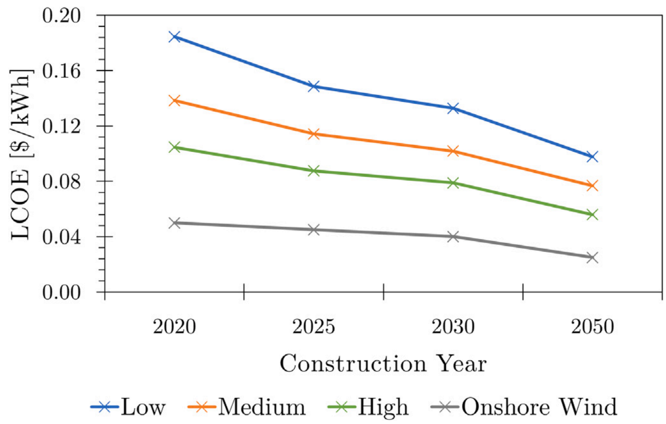


**Fig. 2.** LCOE of 1 GW/100 km HIS (with H2GT) in comparison with cost of onshore wind.

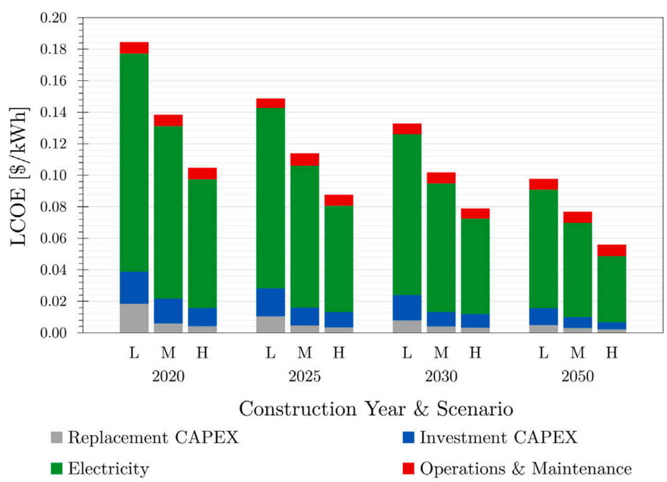


**Fig. 3.** LCOE breakdown of 1 GW/100 km HIS (with H2GT).

and demand. The system consists of a 100 cm diameter pipeline, with a H2GT connected to the pipeline outlet to generate AC electricity.

The LCOE ranges from 0.105 to 0.184 $/kWh for construction in 2020, with the lowest cost range at 0.056 to 0.098 $/kWh for construction in 2050.

Fig. 3 provides a breakdown of the LCOE into its CAPEX and OPEX components. The LCOE of the system over its lifetime is dominated by the cost of input electricity, contributing 75 to 80% to the total value in all scenarios. This is due to the low efficiency of the system in all cases, resulting in between 2 and 4 times the amount of electricity delivered at output being demanded at input to the electrolyser. Following this, the main driver of the decrease in LCOE over time is the improvement in electrolyser efficiency, which increases the total system efficiency from 32.4 to 48.4% in the case of the 'medium' scenario, reducing the lifetime electricity demand by a 30%. This combined with the decrease in cost of onshore electricity from wind (as shown in Fig. 2) results in lower operating costs for the electrolyser and compressor.

Fig. 4 shows the total cost of the HIS excluding the cost of electricity, presenting the cost contributions of each component. The graph shows that the reduction in total cost is driven mainly by the decrease in costs of the electrolyser. This in turn is most affected by the lowering of CAPEX/kW of the component, decreasing by an average of 64.3% between 2020 and 2050 across the three scenarios. In addition, the lifetime of the electrolyser is predicted to more than double by 2050, and the stack replacement cost (as % of CAPEX) is expected to decrease by 20%. The combination of these factors results in the electrolyser


**Fig. 4.** Composition of total system cost of 1 GW/100 km HIS (with H2GT, excluding electricity costs).

shifting from being the main contributor to the total system cost for construction in 2020 and 2025 to contributing as low as 14% of the total cost in 2050 in the 'low' scenario.

The pipeline has a relatively low contribution to the CAPEX of the system, at <2% across all scenarios. This would suggest that longer pipeline distances could be more economically viable for the system, which is considered in more detail in Section 5.2. Similarly, the compressor contributes only 3% to the system CAPEX in 2020, with the contribution decreasing to zero in 2050, due to the improvements in electrolyser output pressure removing the requirement for a compressor. This suggests that while a compressorless HIS is possible in the long term with the increased maximum output pressure of PEM electrolysis, the improvements are minimal when considering the economics of the system. Instead, the main benefits of compressorless systems are likely to be the improvement in overall system efficiency and reliability.

Fig. 4 also shows the increase in cost contribution of the H2GT to the total cost of the system over time. Given that the component has minimal cost improvements over time, the contribution becomes more significant, contributing up to 83% of the total costs in 2050, demonstrating that the H2GT is likely to be the greatest obstacle to cost competitiveness of the HIS.

With the H2GT making such a significant contribution to the total cost of the system in later construction years, it is therefore necessary to compare the LCOE of the H2GT system to that of a system using PEMFCs in combination with grid scale converters to generate AC electricity from hydrogen flow. Despite currently having 4x higher capital costs and 14% lower efficiency when compared with a H2GT, PEMFCs have significant technology and cost improvements expected over time—in contrast with the H2GT system. Fig. 5 shows the difference in LCOE between the cost of a H2GT and PEMFC system. On average across the three scenarios, the LCOE is 28% higher for construction in 2020, and 17% higher in 2025. This is due in part to the higher CAPEX/kW of the PEMFC system, but is mainly due to the efficiency being 10 to 15% lower than the H2GT: the lower efficiency when generating electricity from hydrogen results in more electricity demanded at the electrolyser to achieve the same 1 GW capacity, significantly increasing electricity costs to the system when a PEMFC is used. This is compounded by the higher cost of electricity from onshore wind in 2020 and 2025. In these construction years, the lower replacement cost of PEMFCs compared with GTs is not sufficient enough to offset the increase in initial capital cost and electricity demand at input. However the improvements in efficiency, replacement cost and lifetime of the PEMFC system means that the LCOE approximately reaches parity with that of the H2GT system in 2030 at 6% higher average LCOE, and a 0.1 ¢/kWh lower

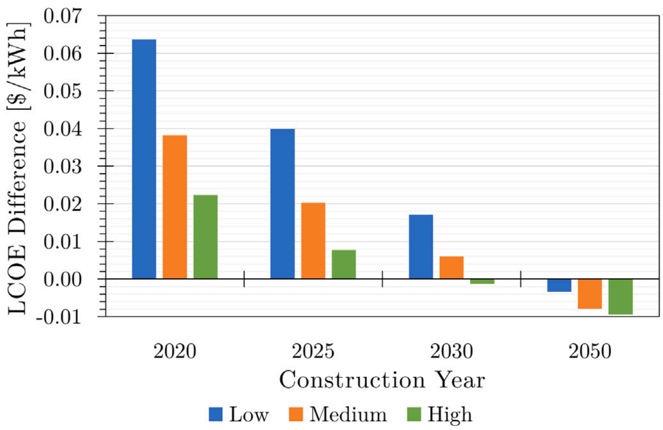


**Fig. 5.** Comparison of LCOE with H2GT, Fuel Cell cheapest option.

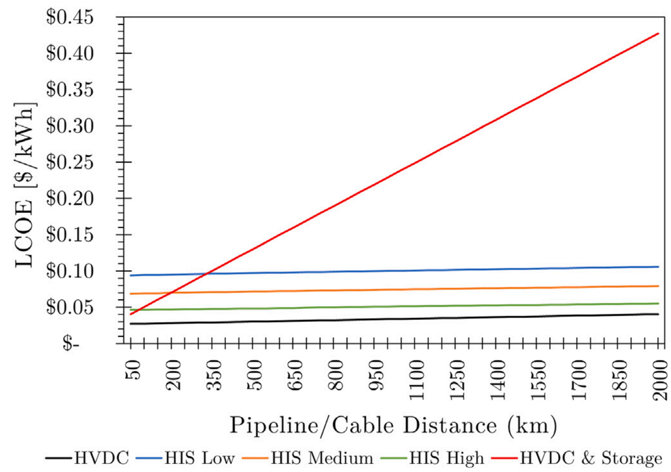


**Fig. 6.** Sensitivity of LCOE with distance for a 1 GW system, constructed in 2050. HIS and HVDC underground compared.

cost in the 'high' scenario. This trend continues into 2050, with LCOE becoming 0.3–0.9 ¢/kWh lower than the H2GT.

Overall, the most cost competitive HIS would consist of a H2GT in the short to medium term, with PEMFCs becoming the more desirable option in 2050. Therefore, the following cost-distance and LCOS analyses are carried out considering the HIS constructed with a H2GT in 2020 to 2030, with a PEMFC and converter used for construction in 2050.

### 5.2. LCOE-distance sensitivity

As shown in Section 4, the overall efficiency of the HVDC system is over 90%, which is between 40 and 65% higher than that of the HIS. The data presented in Fig. 5 suggests that the HIS may only be competitive with HVDC for construction in 2050. Under this configuration, the lower CAPEX of the electrolyser and PEMFC, as well as high efficiency could reduce the LCOE of the HIS sufficiently to compete with HVDC cables, which are less cost sensitive to the system capacity. This scenario is the focus of the LCOE-distance sensitivity analysis in this section.

Fig. 6 describes the sensitivity of LCOE to distance in the case of a 1 GW system with a pipeline diameter of 100 cm, constructed in 2050, comparing the PEMFC system to that of an HVDC underground system. When purely considering the usage of the system to transport electricity, the HIS system could not achieve cost parity for distance up to 2000 km. However, it is important to note that the comparison of LCOE does not take into account the added benefit of embedded storage within the pipeline. Fig. 6 also shows the LCOE-distance sensitivity of an HVDC system with the same amount of storage as the HIS, assuming the pipeline can discharge to 90% of initial pressure every 2 days. The HIS reaches cost parity with the HVDC system at distances <350 km across all scenarios. This demonstrates the potential of the HIS to act as a low cost, large capacity storage system while delivering energy across long distances, which is investigated in the next section.

### 5.3. LCOS analysis

Fig. 7 shows the LCOS of all scenarios for the base case of a 1 GW/100 km system, based on a pipe diameter of 120 cm. Energy is discharged once a day by decreasing the average pipeline pressure to 75% of normal (approximately 10 MPa to 7.5 MPa), corresponding to a storage capacity of 2 GWh. This corresponds to usage of the system as a 'short duration' means of storage, with 365 cycles per year. The LCOS of the system decreases from an average of 0.732 $/kWh in 2020 to 0.398 $/kWh in 2050. The total costs of the system are identical to that used in the LCOE calculation, therefore the drivers behind the decrease

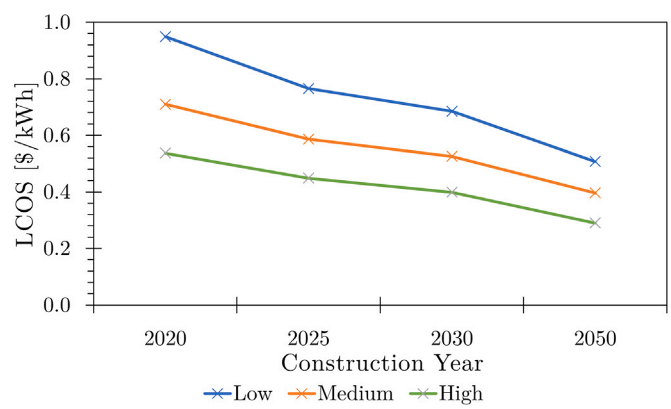


**Fig. 7.** LCOS of 1 GW/100 km HIS .

in LCOS with time are the same as in Section 5.1, with the efficiency improvements of the electrolyser and reduction in cost of electricity reducing total costs by the greatest amount. The usage of the PEMFC in 2050 results in a slightly higher efficiency for conversion to electricity, meaning that the amount of electricity discharged per cycle increases, improving the LCOS reduction.

Jülch (2016) provides LCOS data for 'short duration' storage technologies for 2030, which are compared below. The LCOS of the HIS system in 2030 is between 0.398 and 0.685 $/kWh, compared to a LCOS for a range of battery technologies of 0.19 to 0.22 $/kWh, suggesting the system will not be competitive with battery technologies from a storage perspective. However, these results suggest that the HIS may be competitive with alternate gaseous storage methods: Jülch (2016) gives a LCOS of natural gas storage of 0.40 $/kWh, which is higher than that of the HIS when considering the more optimistic 'high' scenario. Further investigation into discharge rates, storage use case and effect of discharging on hydrogen embrittlement would be beneficial to more accurately compare storage capabilities of the HIS with these technologies.

Fig. 8 shows the difference in LCOS between the HIS and HVDC + storage system. The LCOS of the HIS is between 0.011 and 0.515 $/kWh higher in 2020, with costs becoming much more competitive in 2020 at 0.044 $/kWh higher in the 'medium' scenario, and 0.115 $/kWh lower in the 'high' scenario. This trend continues into 2030, with the 'medium' scenario having a lower LCOS in addition to the 'high' scenario, and in 2050 the HIS has a competitive LCOS in all scenarios, at between 4 and 33% lower than the HVDC + storage system. Overall

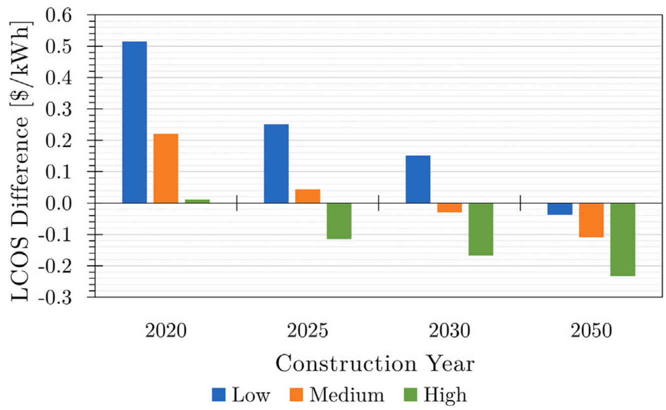


**Fig. 8.** LCOS difference between HVDC+storage and HIS, HIS cheapest option.

**Table 3**
Inputs and outputs for case studies.

| Case study | 6.1 | 6.2 | 6.3 |
|---|---|---|---|
| **Inputs** | | | |
| Capacity (MW) | 500 | 4,000 | 1,500 |
| Total Length (km) | 127 | 810 | 2,500 |
| Pipeline Diameter (cm) | 120 | 50 | 50 |
| Storage Discharge % | 99% | 75% | 90% |
| Charge/Discharge Rate (cycles/day) | 20 | 0.5 | 1 |
| **HIS Outputs** | | | |
| Initial Investment Cost (M$) | 4,047 | 9,490 | 14,728 |
| LCOE ($/kWh) | 0.078 | 0.150 | 0.180 |
| LCOS ($/kWh) | 0.446 | 0.482 | 0.192 |
| **HVDC System Outputs** | | | |
| Initial Investment Cost (Actual) (M$) | 281 | – | – |
| Initial Investment Cost (Model) (M$) | 537 | 11,821 | 17,363 |
| LCOE ($/kWh) | 0.033 | 0.063 | 0.086 |
| LCOS ($/kWh) | 0.803 | 0.528 | 0.799 |

these results shows that despite the lack of competitiveness when solely considering electricity delivery, HIS would be a more attractive system than an HVDC system from a storage perspective from as early as 2025.

## 6. Case studies

In this section, the HIS model is applied to three case studies, in order to demonstrate the 'variety of use' cases for the system. Each example has a unique set of requirements for the system including: input electricity source, pipeline configuration and length, and system capacity. Inputs to the model have been adjusted to account for these differences. The following main techno-economic outputs have been generated to evaluate the feasibility of each case; LCOE, LCOS, and total investment cost. In addition, each case study is compared with an equivalent HVDC system from a techno-economic perspective, and discussed in the context of each specific use case. A summary of the input/output data for all case studies is given in Table 3, with all costs in $\$_{2020}$, calculated for construction in 2030. Maps highlighting the pipeline route and key points can be found in the Appendix.

### *6.1. Moyle interconnector*

The HVDC Moyle interconnector provides a bi-directional link between the electricity systems in Ireland and Great Britain, carrying 500 MW across the 64 km distance between coasts (Harvey et al., 2001). The system consists of a 63 km HVAC overhead line between the National Grid and Auchencrosh on the coast of Scotland, AC–DC conversion, transmission via 2x ±250 kV subsea DC cables, and reconversion to AC at Northern Ireland. There have been significant changes since its construction in 2002: increased grid penetration of renewable technologies and new market mechanisms such as intra-day trading have resulted in the system becoming increasingly outdated. In addition, due to grid constraints at either side, the system flow has been limited to 400 MW. Following this, a major refurbishment project is underway to extract more performance from the system.

This case study investigates the prospect of using a HIS to transport electricity between the two islands as an alternative to the existing HVDC system. The main benefit of using the system over HVDC is the embedded storage within the pipeline: seasonal and intra-day storage would enable increased renewable supply to the link while increasing the potential capacity. Furthermore, the need for frequency support could be reduced if the linepack is charged and discharged at a high frequency. These factors would increase utilisation of the link, and reduce costs of intermittent renewable energy by allowing 'firming' of renewable energy prices during trading.

The proposed hydrogen interconnector consists of a 127 km pipeline (64 km onshore + 63 km subsea), with a combined electrolyser/H2GT plant located at either end to enable bi-directional transport. A 120 cm diameter pipe is used to maximise storage capacity, and it is assumed that storage capacity is used primarily for frequency support, with 20 discharge cycles a day to 99% of initial pressure.

The initial investment cost and LCOE of the system is 7.5x higher than the equivalent HVDC system, however the majority of the cost difference is made up for by the increased capability of the system over HVDC: the HIS offers a 0.357 $/kWh lower LCOS, as well as having more flexibility in terms of storage use case.f This will likely offset the cost of added power electronics converters and storage which would need to be added to the HVDC system to enable the same functionality.

### *6.2. Offshore wind—North Atlantic Ocean*

Deep sea wind farms have the potential to harness large quantities of renewable energy in locations further from shore, where wind energy is stronger and more reliable. Currently, offshore wind farms are located relatively close to shore in the UK, at distances less than 100 km (Crown Estate, 2021). However, new technology developments – specifically floating offshore wind – and increases in wind energy capacity will inevitably result in more large scale wind plants being built further offshore in the medium/long term. One location of interest for this purpose is in the North Atlantic Ocean in the west of Scotland, where there is over 60,000 km$^2$ of land available to harness wind energy (Atkins Geospacial, 2021). Wind farms located up to 500 km from the coast would likely suffer extreme cases of stranded electricity supply, and will also require large scale storage to increase security of supply to mainland electricity grids. Following this, the focus of this case study is the transport of offshore wind energy to areas of high demand via sub-sea hydrogen pipeline.

The case study considers a renewable energy source of a large scale, 4 GW floating offshore wind farm 500 km due west of Inverness in the North Atlantic Ocean. Energy is converted into hydrogen at the wind farm using PEM electrolysers, transported approximately 800 km to the coast at Liverpool, UK, where it is reconverted back to electricity for utilisation. This system represents a high capacity, long distance use case for the HIS, using offshore wind energy prices for electricity price considerations. To reduce costs, a 50 cm diameter pipeline is considered, with low frequency charging/discharging to account for intermittency of the farm: the pipeline is discharged to 75% of initial pressure, cycled every 2 days.

The results show that despite having a 0.087 $/kWh higher LCOE, the HIS has a 2331 M$ lower initial investment cost, due to the high capital cost of using 2x 1 GW HVDC subsea cables outweighing the cost of the electrolyser and H2GT. The hydrogen system also performs better than HVDC from a storage perspective, with a levelised cost 0.046 $/kWh less than the equivalent HVDC system using salt cavern storage.

### 6.3. Solar power—Morocco to UK interconnector

The final case study considers a similar scenario to that of Case Study 6.2: a large capacity, long distance system. However, this system considers solar power as the input electricity source, using prices sourced from (International Renewable Energy Agency, 2019). The system considers the delivery of 1.5 GW of solar power from Morrocco to Southampton, UK. Such a system could be used to enable energy trading between the two countries, as well as diversifying the renewable supply in the UK: Morocco has significantly greater access to solar energy, with a 2 GW plant already in operation in Ouarzazate, and is expected to scale up solar electricity production significantly towards 2050 (Wei et al., 2021). As a result, the importing of solar energy from Morocco would help reduce over reliance of the UK grid on wind energy, which may help ease the transition away from fossil fuels.

The results shown in Table 3 demonstrate the lower costs of the HIS at extremely long distances, with an initial investment cost 2635 M$ less than the equivalent HVDC system. In addition, the HIS has significant advantages from a storage perspective, with a LCOS 4x less than that of the HVDC system. This demonstrates the benefits of the HIS when used for large scale storage.

## 7. Conclusions

This paper presents the techno-economic analysis of a Hydrogen Interconnector System (HIS), using the Levelised Cost of Electricity/Storage (LCOE/LCOS) methods. The cost of electricity was determined for the base case of a 1000 MW, 100 km system under 'high', 'medium' and 'low' scenarios, based on construction years in 2020, 2025, 2030 and 2050. The system was compared with an equivalent High Voltage Direct Current (HVDC) system in all scenarios, and applied to 3 case studies.

The results show that the total cost of the HIS is highly sensitive to the cost of input electricity and efficiency of the hydrogen–electricity or electricity–hydrogen conversion. The compressor and pipeline both contribute less than 2% to the total capital costs of the system, resulting in minimal economic benefit to a compressorless system or short distance pipeline. The most cost effective HIS uses a gas turbine at pipeline outlet for construction in 2020–2030, being replaced by a fuel cell combined with a Direct Current to Alternating Current converter in 2050.

The system is competitive with HVDC (same amount of storage) from a LCOE perspective for all scenarios when considering construction in 2050, with lower costs at distances above 350 km for a 1 GW system. The system has a lower LCOS than an HVDC system using long duration hydrogen storage for construction from 2030, with the potential to be competitive in 2025. The HIS outperforms the HVDC from storage perspectives for all case studies, with 15%–20% lower investment costs for 2 case studies analysed.

## CRediT authorship contribution statement

**Max Patel:** Methodology, Software, Investigation, Writing – original draft. **Sumit Roy:** Conceptualization, Supervision, Writing – review & editing. **Anthony Paul Roskilly:** Funding acquisition, Writing – review & editing. **Andrew Smallbone:** Supervision, Resources, Writing – review & editing.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Acknowledgements

This research work was funded by the Engineering and Physical Science Research Council of UK (Grant numbers: EP/T022949/1 and EP/S032134/1).

## Appendix A. Supplementary data

All scenario data set and Maps for all the case studies can be found online at https://doi.org/10.1016/j.jclepro.2021.130045.

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